BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY d/b/a CONECTIV POWER DELIVERY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES FOR ELECTRIC SERVICE	**) BPU DOCKET NO. ER02080510** **) OAL DOCKET NO. PUC 06917-02**

INITIAL BRIEF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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Dated: March 24, 2003

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I. PROCEDURAL HISTORY

A. RESTRUCTURING PROCEEDINGS AND ORDERS

On April 30, 1997 the Board of Public Utilities ("Board" or "BPU") issued an Order adopting and releasing its Final Report on electric industry restructuring entitled "*Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations"* ("Final Report"). The Final Report set forth the Board's goals and requirements for the deregulation of the generation segment of the traditional electric utility monopoly. The goal was to deregulate generation and increase competition in both retail and wholesale markets in order: l) to reduce electric rates for all ratepayers; 2) to expand choices of services and products for all consumers; and 3) to foster competition. The Final Report required the four electric utilities to make three restructuring filings by July 15, 1997: (1) a stranded costs filing; (2) a rate unbundling filing; and (3) a filing addressing functional restructuring and other important policy issues.

In mid-September 1998, the New Jersey Legislature introduced comprehensive legislation that restructured the monopoly electric and natural gas industries in the State. Two identical bills, Senate Bill 5 (S-5) and Assembly Bill 10 (A-10), drafted by the BPU, contemplated full retail competition by mid-1999 and 5% rate reductions for all electric utility customers by August 1999 with a 10% rate reduction by August 2002.

After extensive legislative hearings which continued through the end of 1998, and review of several revised versions of the bill, P.L. 1999, C. 23, the *Electric Discount and Energy Competition Act* ("Act" or "EDECA")[1] was signed into law on February 9, 1999. As required by the Final Report, the four utilities filed restructuring filings in July 1997 and, as a result of those proceedings, the Board issued a Final Decision and Order approving Atlantic City Electric Company's d/b/a Conectiv Power Delivery ("Atlantic" or "Company") unbundled rates into their various components pursuant to EDECA including the establishment of separate Delivery Charges as well as a non-bypassable market

[1] Later codified as *N.J.S.A.* 48:3-49 *et seq*.

transition charge ("MTC") and a non-bypassable societal benefits charge ("SBC"). *In the Matter of Atlantic City Electric Company- Rate Unbundling, Stranded Costs, and Restructuring Filings*, Final Decision and Order, BPU Docket Nos. EO97070455, EO97070456, and EO97070457, (Order Dated March 30, 2001) ("Final Order" or "*J-1*")

Pursuant to the Board's directive in the Final Order, Atlantic filed a petition with the Board on August 1, 2002, requesting approval of proposed changes to its unbundled rate schedules. Atlantic is proposing changes to the Market Transition Charge ("MTC"), Net Non-Utility Generator Charge ("NNC") and Societal Benefits Charge ("SBC"). Some of the stated reasons for the proposed changes were: 1) to commence recovery of the Deferred Balance set up under the Final Order; and 2) to set the MTC, NNC and SBC at the appropriate levels in order that the costs associated with those unbundled rate elements are collected on a current basis. The Company filed to recover the deferred balance of $176.4 million including interest amortized over 4 years. The net effect of the proposed changes would be an annual increase in rates of $71.6 million or an annual increase of 8.4% over the 4 year period. *P-2*.

This case was forwarded to the Office of Administrative Law ("OAL") on August 29, 2002 as a contested matter and assigned to the Honorable Diana C. Sukovich, Administrative Law Judge ("ALJ"), for evidentiary hearings.

In addition to the Company, the parties to this proceeding include the Staff of the Board ("Staff") and the New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate"). The Independent Energy Producers of New Jersey ("IEPNJ") and New Jersey Large Energy User Coalition ("NJLEUC") were granted intervenor status. Jersey Central Power & Light Company ("JCP&L"), Cogentrix Energy, Inc. ("Cogentrix")[2], Rockland Electric Company ("RECO") and PPL Energy Plus, LLC ("PPL") were granted

[2] Cogentrix filed a Motion to Intervene on October 24, 2002. By Order issued on December 9, 2002, ALJ Sukovich denied intervenor status to Cogentrix but granted participant status. On December 26, 2002, Cogentrix filed a motion with the Board for interlocutory review. Atlantic filed a motion in opposition. A second motion was filed by Cogentrix on December 20, 2002 seeking to modify the procedural schedule set by the ALJ. In an Order issued on January 15, 2003, the Board upheld the ALJ denial of Cogentrix's request for intervention and instead granted Cogentrix participant status.

participant status.

A pre-hearing conference was held before Judge Sukovich on November 26, 2002, and a Pre-Hearing Order was entered on December 4, 2002. In accordance with the schedule set forth in the Pre-hearing Order, discovery was propounded. A public hearing was held in Mays Landing on January 29, 2003.

In support of its deferred balance rate filing, the Company with its August 1 petition filed the testimony of Charles F. Morgan, Jr. (Overview of the Filing), Jerry Elliott (Basic Generation Service Procurement Issues (BGS)), Herbert A. Chalk (Actual and Forecasted Deferred Balance), and Joseph F. Janocha (MTC, NNC and SBC Charges). On August 30, 2002, the Company filed the supplemental testimony of Charles F. Morgan, Jr.

The Ratepayer Advocate filed the Direct Testimony of Andrea C. Crane and James A. Rothschild on January 3, 2003. On January 24, 2003, the Company filed Rebuttal Testimonies of Charles F. Morgan, Jr., Jerry Elliott, and Herbert A. Chalk.

Evidentiary hearings were held at the OAL on February 19, 20, 21, 24 and 27, 2003. At the close of the evidentiary hearings a briefing schedule was set, with initial briefs due on March 14, 2003, and reply briefs due on March 20, 2003. The filing of initial briefs were subsequently extended to March 24, 2003 and the filing of reply briefs was extended to April 7, 2003.

B. AUDITS OF DEFERRALS

In compliance with the Board's directive at the Agenda Meeting held on July 23, 2002, a letter was sent from the Division of Audits and Division of Energy pursuant to *N.J.S.A.* 48:2-16.4 requesting bids from auditors/consultants to initiate management audits on each of the four New Jersey investor-owned electric utility companies. The auditors were to focus on the restructuring-related deferred balances of electric utilities. The firms of Mitchell & Titus LLP ("M&T") and Barrington-Wellesley Group ("BWG") were hired to assist with the review of Atlantic. Pursuant to the Board's letter, the audit reports were to be transferred to the OAL on January 15, 2003. By letter dated February 24, 2003, a copy of the auditors' report was transferred from the Board to ALJ Sukovich and copies were provided to the parties in the proceeding. Evidentiary hearings relating to the audit were held on February 27, 2003, at which time representatives from the audit firms were cross examined.

II. DEFERRAL ACCOUNTS

The Ratepayer Advocate has made significant adjustment to Atlantic's proposed recovery of Deferred Accounts. A summary of the proposed adjustments are set forth as follows:

EXHIBIT 1

RATEPAYER ADVOCATE SUMMARY OF ADJUSTMENTS*
(000)

1.	Company Claimed BGS Deferral		($72,512)
2.	Energy	($25,527)	
3.	Capacity	($ 3,375)	
4.	Capacity - Audit Recommendation	($ 6,100)	
5.	LEAC	($ 1,993)	
6.	BGS Admin.	($ 3,528)	
7.	Total BGS Adjustments		($40,523)
8.	**Ratepayer Advocate BGS Deferral**		**($31,989)**
9.	Company Claimed NUG Deferral		$ 6,365
10.	Logan Arbitration	$2,477	
11.	Tax Refund Interest - Audit Rec.	$ 459	
12.	**Ratepayer Advocate NUG Deferral**		**$9,301**
13.	Company Claimed MTC Deferral		($125,682)
14.	Cash Working Capital	($ 3,793)	
15.	Consolidated Billing	($ 4,052)	
16.	Regulatory Restructuring	($15,307)	
17.	To-be-divested Generation	($29,569)	
18.	Regulatory Asset - Audit Rec.	($ 2,617)	
19.	Total MTC Adjustments		($55,338)
20.	**Ratepayer Advocate MTC Deferral**		**($70,344)**
21.	Company Claimed SBC Deferral		$20,083
22.	Uncollectibles - Audit Recommendation		$ 1,417
23.	**Ratepayer Advocate SBC Deferral**		**$21,500**

Note: Negative amounts denote under-collections; positive amounts denote over-collections.
*The Ratepayer Advocate has recalculated the Company's position based on January 2003 updates.

A. STARTING BALANCE FOR DEFERRAL

1. Atlantic Electric failed to credit ratepayers for interest on LEAC over-recoveries in the amount of $1,993,000.

In the Atlantic Final Order, the Board determined that over-recovered balances, including interest, from the Company's Levelized Energy Adjustment Clause ("LEAC") and Demand Side Management ("DSM") program were to be used as the starting point for the Deferred Balance beginning August 1, 1999. *J-1* at 73.

Atlantic booked a total LEAC over-recovery balance of $50,002,000 as a credit to ratepayers to be netted against the BGS component of the Deferred Balance. *P-11* at 5, Sched. HAC-1 updated, p.1 of 5. The Board's auditors did not examine the Company's deferred balances as of August 1, 1999. *AUD-2* at 1; T872:L11-17. One of the auditors, Mitchell & Titus, merely presented the Company's "starting point" in its schedule of deferred balances with the disclaimer "for information purposes only." *Id*.

However, the Ratepayer Advocate's witness Andrea Crane did examine the LEAC credit used by the Company to offset the deferred balance as of August 1, 1999, and has determined that the Company's starting balance credit to the customers (i.e., the beginning deferred balance) was understated by $1,993,000. The Company had failed to calculate the interest due to the ratepayers correctly. The actual over-recovered BGS balance as of August 1, 1999 was $51,995,000. *RA-2* at 2, Sched. ACC-2 updated, p. 1 of 4.

In determining the LEAC balance, Atlantic calculated a monthly interest amount each month from June 1997 though August 1999 and netted the monthly interest to determine the net interest payable to ratepayers. *RA-2* at 2. Because the Company netted out every month from June 1997 through July 1999, the final result of the Company's interest calculation over the approximate two year period was that no interest was due to ratepayers. *Id*. However, the interest calculation, when done properly, truing-up on a yearly basis, results in interest owed to ratepayers of $1,995,000. *Id*.

N.J.A.C. 14:3-13.4 defines the Board's policy on the calculation of LEAC interest as follows:

> (c) Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the clause period.
>
> (d) Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (over-recoveries) for the clause period.
>
> (e) A cumulative net positive interest balance at the end of the clause period is owed to customers and shall be returned to customers in the next clause period. A cumulative net negative interest balance shall be zeroed out at the end of the clause period.
>
> (f) The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the clause period. The positive interest balance shall be rolled into the beginning overrecovery balance of the subsequent clause period.

[*N.J.A.C.* 14:3-14.4(c)-(f).]

The Board is long standing policy provide that LEAC interest is to be calculated each month with an annual, not a multi-year, true-up period.[3] If, at the end of the LEAC year, interest is owed to the ratepayers, that interest is credited to ratepayers through the LEAC mechanism. If interest is owed to the utility, the utility eliminates that interest through appropriate accounting entries. Interest should therefore be examined in discrete 12-month intervals to determine if the Company owes ratepayers interest on any LEAC over-collections. *RA-2* at 21-22; T649:L21-T650:L7.

Traditionally, the true-up period is a 12-month period; however, Board regulations do allow the use of a different period if the *Board specifically finds such to be appropriate* within the context of an appropriate rate proceeding. *N.J.A.C.* 14:3-13.4(a); T650:L12. Company witness Mr. Chalk erroneously argued that the Company's 26-month interest

[3] *I/M/O Atlantic City Electric Company Increasing Rate Schedule E.A. (Energy Adjustment)* Tariff, Docket No. ER88091053 (Order Modifying Initial Decision dated May 30, 1990), at 13; *Id*., Initial Decision dated June 22, 1989, at 9-13, citing *I/M/O Atlantic Electric Company Decreasing Its Rates, etc. (App. Div. April 21, 1989, Docket No. A5124-87T5) (unreported); I/M/O Public Service Electric & Gas Co. for Approval of Notification in its Tariff for Electric Service*, Implementation of a Levelized Energy Adjustment Clause, Docket No. 776-492 (Order dated June 30, 1977), at 1; *Atlantic City Electric Company Tariff*, First Revised Sheet, No.68B eff. June 8, 1998.

calculation was correct because no party had objected to an extended true-up period in Atlantic's 1998 LEAC filing (which was never implemented). *P-13* at 4; T411:L14; T408:L21; T409:L9. What Mr. Chalk fails to realize is that the burden of bringing the issue before the Board lay with the Company and not with the parties to the LEAC proceeding. As the regulation states, it is at the discretion of the Board and not the Company to determine whether a longer or shorter true-up period is appropriate. The Company usurps the Board's powers by making such determination unilaterally.

Furthermore, while it is true that no party to the 1998 LEAC objected to an extended true-up period, the true-up period was not an issue in that case. The only element of a LEAC that depends to some extent on the length of the true-up period is interest. T649:L14. Consequently, if the period has no impact on interest, there is no reason to raise the issue of the length of the period. T650:L14. Thus, there was no reason for the Ratepayer Advocate or any other party to raise the length of the true-up period as an issue while the Company had an affirmative duty to do so if it intended to change the true-up period. T650:L23.

Based on Atlantic's commonly used June to May LEAC year, Ms. Crane calculated interest for the 12 months ending May 1998 and for the 12 months ending May 1999. For the year ending May 1998, no interest was owed to ratepayers. *RA-2* at 22. However, for the 12 months ending May 31, 1999, the Company owed its ratepayers $1,306,000 in interest. Ms. Crane then made an additional adjustment of $687,000 for the months of June and July 1999. Thus, the Company's customer credit starting for its BGS Deferred Balance is understated by $1,993,000 and should be adjusted. *RA-2*; Sched. ACC-2, updated.

B. BGS DEFERRAL AMOUNTS

The full recovery of the proposed deferred balance will have an unprecedented impact on the rates paid by the customers of the Company. The promise of EDECA was to lower rates and to provide better quality of service to energy consumers in New Jersey through competition. Just four years after the start of restructuring, the ratepayers of New Jersey are faced with little choice in competitive suppliers of electricity, a deferred balance of the four electric utilities over $1 billion and a rate impact that may be as high as a 8.5 % increase for Atlantic's customers over the 4 years amortization period (in addition to the base rate increase proposed by the Company). In sum, if the proposed deferred balance costs are fully recovered by the Company, such corresponding rate increase will have a significant negative impact on New Jersey's economy and to New Jersey's utility customers.

The Board has broad and sweeping powers over all aspects of public utilities subject to its jurisdiction. *See N.J.S.A.* 48:2-13; *Township of Deptford v. Woodbury Town Sewerage Corporation*, 54 *N.J.* 418 (1969); *In re Public Service Electric and Gas Company*, 35 *N.J.* 358, 371 (1961). The Board is the regulatory agency with jurisdiction and control over electric public utilities, including jurisdiction to set rates. *N.J.S.A*. 48:2-21. It is established law in New Jersey that a public utility is required by statute to show that an increase in rates is just and reasonable. *Id.* The statute is clear that "the burden of proof to show the increase, change or alteration is just and reasonable shall be upon the public utility making the same." *N.J.S.A*. 48:2-21(d). A long line of cases in New Jersey supports the premise that the burden of proving reasonableness of costs lies with the Company. See, *I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates -Hope Creek Proceeding*, BPU Docket No. ER85121163 ("*Hope Creek Order*"), where the Board held that "[i]t is uncontroverted that Public Service had the burden of proving the reasonableness of its expenditures for Hope Creek as only reasonable costs can be included in rate base and permitted to earn a return." See also, *Public Service Coordinated Transport v. State*, 5 *N.J.* 196, 222 (1950).

EDECA and the Final Order specifically state that only "reasonable and prudently incurred costs" claimed by an electric public utility to provide BGS may be recovered.

N.J.S.A. 48:3-57(e); *J-1* at 88. The burden of proof that the deferred balance claimed by the Company is just and reasonable lies with the Company, as supported by precedent in the State.

In evaluating whether the Company met its burden that it acted reasonably and prudently during the transition period, the Board must evaluate the managerial conduct in light of the circumstances, information and options in existence at the time when management decisions were made. Quoting the New York Public Service Commission ruling, the Board stated that:

> The Company's conduct should be judged by asking whether the conduct was reasonable at the time, under the circumstances considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people could have performed the tasks that confronted the Company.

[*Hope Creek Order* at 65-66.]

The *Hope Creek Order* further clarifies the Board's standard of review when determining prudency:

> [T]he Company, as discussed earlier in this Order, had the burden of proof with respect to the reasonableness of the costs that were expended in building the plant. In order to meet that burden with respect to the various enhancements, the Company had to show the reasons why each of the enhancements were installed and the benefits to be derived from their installation. An integral part of the benefits associated with the enhancement is a justification of the costs.

[*Id.* at 89.]

Thus, it is clear that the present deferred balance prudency review must apply the standards set forth in the *Hope Creek Order* and determine whether: 1) the Company's actions during the transition period met the reasonable person standard given the specific circumstances at the time decisions were made; and 2) the Company has sufficiently shown the reasons why each BGS cost was incurred and the benefits derived by the

Company's actions. Moreover, the Board must review whether the Company sufficiently mitigated risk. Under the Final Board Order, the Board recognized the possibility of run-up of the deferred balance, when it noted that the Company is required to "endeavor to mitigate such risk." The Board further stated:

> By virtue of the price cap mechanism, a run-up in market prices above those assumed in establishing the BGS rates could result in an under-recovery of NUG stranded costs, which in turn could lead to a buildup in the Deferred Balance. Accordingly, it is in the public interest for ACE to pursue the mechanisms identified in paragraph 11 of Stipulation 1 to hedge against purchases of power for BGS in the open market.

[*J-1* at 78]

The following discussions will show that the Company failed to fully document its BGS procurement decisions and made imprudent decisions for a large portion of the Deferred Balance. Ultimately, the Board must determine whether the proposed recovery of the deferred balance is in the public interest.

1. Atlantic's Procurement Procedures were Flawed and Imprudent.

As stated earlier, in evaluating Atlantic's performance in BGS procurement, Your Honor and the Board must apply the standards set forth in the *Hope Creek Order* and determine whether: 1) the Company's actions during the transition period met the reasonable person standard given the specific circumstances at the time decisions were made; and 2) the Company has sufficiently shown the reasons why each BGS cost was incurred and the benefits derived by the Company's actions. Based on this standard, Atlantic's BGS procedures were neither reasonable nor prudent. BGS costs in the sum of $40,523,000 should therefore be disallowed.

Atlantic Electric is projecting a total BGS deferral of $72,512,000 by the end of the transition period. *P-12*; Sched.HAC-10 updated, p. 2 of 2. As a result of the Company's improper and imprudent procedures, Atlantic's BGS deferred balance should be reduced by $40,523,000 to $31,989,000. *RA-2,* Sched. ACC-1 updated; Sched. ACC-2 updated, p.4 of 4; Sched. ACC-2A updated, p. 4 of 4. The Ratepayer Advocate's disallowance consists of four components; 1) LEAC credit; 2) energy and capacity issues; 3) excess capacity; and 4) BGS administrative costs. The LEAC credit issue has been addressed in Section II. A. above. The remaining three elements will be addressed separately below.

a. Energy and Capacity

Atlantic's energy and capacity procurement procedures were imprudent and unreasonable. As shown on Exhibit 1 on page 5, the sum of $35,002,000 should be disallowed.

At a minimum, a reasonable and prudent management would have complied with basic rules and procedures established by the relevant regulatory authority. And yet, from the beginning, Atlantic's management disregarded its contractual obligation in the Board approved Settlement Agreement. In the Stipulation, Atlantic agreed that:

> Atlantic shall procure power for BGS through an open, competitive bidding process. During the first three years of the Transition Period, up to and including July 31, 2002, Atlantic plans to solicit proposals (the "RFP Process") for the provision of wholesale supply for BGS in twelve month pricing cycles, or such other cycles as Atlantic deems necessary or prudent. Atlantic will submit its plans for the RFP process to the BPU by September 15, 1999.

[*J-1*, Stipulation, Par. 7]

Moreover, the Board ordered Atlantic to obtain its remaining supply through the competitive bidding process. In the Summary Order, the Board required that:

> ... ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) toward the BGS supply requirement, which power shall be credited at the net BGS price . . . .Such credited prices shall be employed for purposes of establishing the level of owned generation revenue requirement recovery (prior to the completion of divestiture), in accordance with this Order... ACE shall

> solicit request for proposal ("RFP Process") for the provision of wholesale supply for BGS in twelve month pricing cycles, or such other cycles as ACE deems necessary or prudent. ACE will submit its plans for the RFP Process to the BPU by September 15, 1999. ACE shall commence the RFP Process as soon as practicable after such date and approval of the plan by the BPU, with the goal of concluding such process and entering into a contract for BGS supply by December 15, 1999. Any agreements for the provision of BGS shall be presented to, and subject to the approval of, the BPU.

[*J-1* at 87, par. 7]

Despite the clear language of the stipulation and again in the Final Order, Atlantic failed to submit its plans for the RFP process to the BPU by September 15, 1999. *Id*. Atlantic also failed to obtain its remaining BGS supply through the competitive bidding process, as required, until well into the transition period. *AUD-2* VIII-6. In fact, the first RFP submitted to the BPU was RFP II, which was issued in the spring of 2000. *Id.* at Exhibit 8-4. Atlantic failed to comply with Board Orders regarding procurement of BGS supply during the Transition Period as any prudently run New Jersey utility would have done.

Because Atlantic's management failed to plan and execute a reasonable BGS procurement strategy and failed to comply with Board Orders to obtain an approval for a winning bid in a timely manner, the Company paid excessive costs for energy and capacity. The history of the Company's RFP process illustrates its total lack of experience and expertise necessary to execute a successful procurement strategy.

In its discussion of Atlantic's BGS purchases BWG provided a chart[4] showing an overview of Atlantic's BGS RFPs. This chart is reproduced below:

RFP	Date	Energy and Capacity Requested	Period	Results
I IA	10/9/99 10/27/99	Full Requirements Varying energy and capacity amounts by month	1/00 - 7/02 1/00 - 5/00	• 89 solicitations • 2 bids • Rejected bids and relied on PJM spot market
II	4/27/00	300 MW Energy and Capacity 350 MW (required) post nuclear divestiture Bid Revised to request 12-month bid for 300 MW capacity	6/00 - 8/00 Added 9/00 -5/01	• Rejected bids.
III	11/30/00	400 MW unforced capacity credits Varying energy amounts by month (Firm, on-peak)	1/01 - 7/02	• 1 capacity bid, ACE awarded only ½ requested amount (200 MW) • 9 energy bids Awarded to lowest bidder
IV	4/27/01	400 MW Capacity 300 MWN Peak 300 MWH super-peak (1200 to 1900 hrs)	800 MW cap. 6/01 - 9/02 7/01, 8/01, 7/02 7/01, 8/01, 7/02	• Awarded 800 MW capacity, peak energy quantities.

Source: Interview with BGS Portfolio Manager (Interview Summary IR-ACE-7); ACE Reports to the BPU Staff regarding RFP results (DR-ACE-8).

[*AUD-2* at VIII-6 at Exhibit VIII-4]

The Company failed to provide the Board with a plan by September 15, 1999 as the above chart demonstrates and failed to submit an agreement for BGS supply by December 15, 1999. *Id*. Reacting to feedback from third party suppliers, the Company

[4] Please note that the Ratepayer Advocate consultant Andrea Crane did not uses the RFP designation (I, IA, II, III and IV) as used by the Auditors for her testimony RA-2 because Ms. Crane's testimony was filed on 1/3/03 prior to the release of the Audit Report.

restructured the RFP into a short-term wholesale block requirement for the period from January 1, 2000 through May 1, 2000. (See RFP IA in chart above) *Id.* The revised RFP was issued on October 27, 1999. *Id.* The Company received two bids as a result of this solicitation but accepted neither. *Id*.

The first RFP submitted to the BPU was RFP II, which was issued in the spring of 2000. *AUD-2* at VIII-6. This RFP utilized a two-tier approach, requesting bids for 300 MW and 350 MWs of capacity and monthly energy for both on-peak and off-peak periods for the period June through August 2000. This RFP assumed that the Company's nuclear units would be sold. *RA-2* at 13. The Board directed the Company to issue an addendum to the RFP for an alternate 300 MWs of supply for a 12-month period. *Id.* The Company revised the RFP as directed by the Board, but rejected all bids on the ground that the proposed prices resulting from this solicitation were not competitive. *Id.* at 14. The Company continued to use PJM and other spot markets to obtain its BGS supply requirements. *Id*.

Thus, for Atlantic, the first year of the transition period was characterized by futile attempts to procure long term BGS supply. Atlantic's results the following year were just as dismal.

The Board was "deeply concerned" with Atlantic's first year BGS supply procurement procedures, and specifically with its failure to comply with Board Orders. Consequently, the Board decided that the Company should be held accountable for its actions. The Board stated:

> Moreover, the Board cannot ignore the fact that Atlantic has violated its commitment to file for Board approval of the RFP process by September 15, 1999, as set forth in its Stipulation and as approved in the Board's Summary Order. *Atlantic does not now come before the Board with clean hands. Inasmuch as Atlantic has unilaterally opted to purchase capacity and energy in the open market without seeking some specific relief*

> *from its express commitment to the Board and other parties to use a structured competitive process, the Board FINDS the Company should bear the full burden of its actions and be at risk for the consequences thereof.* We do not feelcompelled to sanction the present ramifications and consequences of such indifference by Atlantic to what we consider to be legitimate good faith commitments that all parties had the right to rely upon.

[*J-2* at 3; emphasis added].

The Board warned the Company that "Atlantic must justify any decisions it makes for obtaining energy and capacity for its BGS customers in an appropriate future ratemaking proceeding and show that they are prudent and reasonable. *Id.* at 5.

Although the Company did not control energy prices during the Transition Period, it did have control over its own actions. T618:L19-20. The failure to comply with Board Orders was a decision the Company consciously. Ratepayer Advocate witness Andrea Crane testified; "I think the Company does have to be held accountable for not following through on all of those possibilities." T:L618:L16-619:L25.

The Company's failure to act prudently was in part a result of its employees' lack of the basic tools and training to provide the minimum acceptable level of service in a newly deregulated environment. As the chronology of the RFP process illustrates, Atlantic simply lacked the skills to act prudently. The Board's Auditors testified at the hearing:

> Q Would you consider it to be reasonable and prudent for the Company's management to assure that its decision makers are qualified to make critical supply decisions on behalf of the Company and its Customers?
>
> A (Ms. Lemkul:) Yes.

Q Would you consider it reasonable and prudent for the Company to provide the necessary information and analytical tools to its BGS supply personnel to insure that they make informed and well-reasoned supply decisions?

A (Ms. Lemkul:) Yes.

Q Would you consider it reasonable and prudent for the Company to provide its BGS decision makers with appropriate reports from consultants pursuant to a sufficiently broad scope of work?

A (Ms. Lemkul:) Yes.

Q Would you consider it reasonable and prudent for the Company to consult and work closely with the BPU and the Ratepayer Advocate in creating and implementing the Company's BGS supply strategy?

A. (Ms. Lemkul:) I believe so, yes.

[T991:L18-992:L17]

Atlantic did not follow these basic standards for reasonable and prudent procurement practices. As the Auditors noted, Atlantic did not have qualified personnel and the employees they did have were not provided with the necessary reports and analytical tools. In their report, the Auditors concluded:

> At the outset of the transition period, ACE did not have a full understanding of what the BGS supply process would entail and did not take adequate steps to establish an experienced BGS supply organization. Throughout the first three years of the transition period, ACE had limited in-house staff and did not have analytical resources to consistently make effective decisions regarding BGS supply procurement. . . .

[*AUD-2* at I-10, VIII-25]

BWG further testified that:

Q. If Atlantic put itself in a position in which it was not prepared for whatever reason to make critical BGS decisions affecting its customers, would this constitute imprudence under your standards?

A. (Mr. Wheaton:) I believe it does.

[T969:L5-9]

There were steps that a reasonable management should have taken under the circumstances given at the time. With the commencement of the deregulated environment, Atlantic had a particular obligation to ensure its employees were sufficiently knowledgeable to be able to make reasonable and prudent decisions in order to protect the interest of the Company's ratepayers. And yet, this was not done. *Id.* These were not the actions of a reasonable and prudent management, mindful of ratepayer as well as shareholder interests.

The Company's errors and omissions regarding the RFP process resulted in excessive BGS prices. Especially egregious was the period of July and August, 2001. In November 2000, the Company issued RFP III for the period of January 2001 through July 2002. *AUD-2* at VIII-32. Bids were solicited for on-peak energy and for 400 MWs of capacity. *Id.* Although Atlantic received a capacity bid for 400 MWs at a reasonable price based on the Company's benchmark forecast, the Company only purchased 200 MWs due to concerns about whether the BPU would consider the single bid response to the RFP to be a 'competitive process.' *Id.* The Auditors' analysis indicated that this decision resulted in a $6.1 million increase in BGS costs. *AUD-2* at I-12,VII-56.

In January 2001, rule changes at PJM put pressure on capacity prices. *P-7* at 8; *RA*-2 at 14. At the same time, load growth from new and returning customers increased Atlantic's capacity needs. During this period, the Company basically scrambled to satisfy its capacity obligations, entering into a series of short-term capacity contracts. *RA-2* at 14. In April 2001, the Company issued yet another RFP (RFP IV), requesting bids for capacity from June 2001 through September 2002 and for on-peak energy for the months of July 2001, August 2001 and July 2002. *AUD-2* at VIII-10, VIII-33. As a result of that process, the Company entered into one on-peak energy contract and two capacity contracts. *RA-2* at 14. Various amounts of energy and capacity were acquired pursuant to these agreements through September 2002. *Id*. Since September 2002, all capacity and energy not supplied by Atlantic's own generating facilities or NUG contracts have been provided through the BPU state-wide auction process. *Id.*

The issuance of this RFP for capacity beginning in the peak summer period further demonstrates the Company's poor planning. In fact, Atlantic's entire projected BGS deferral can be traced to July and August 2001, where the deferral totaled more than $78 million. *RA-2* at 17; Sched. ACC-3. If the Company had better managed its costs during July and August 2001, the entire BGS deferral might have been avoided. *Id*. If the Company had entered into long-term contracts in 1999 as anticipated under the Board's Final Order, the high price spikes incurred by the Company might have been avoided. Alternatively, the Company could have entered into hedging agreements to protect against excessive price spikes. As a result of the Company's actions, Atlantic was at the mercy of the market in July and August, 2001, resulting in a massive build-up of the BGS deferral. *RA-2* at 18. Ms. Crane's Sched ACC-3 demonstrates this conclusion. During the first year of the Transition Period, average energy cost per MWh from third party purchases were in the range of $23 per MWh with a high of $54.15 per Mwh in July of 2000. *Id*. In Year 2, average cost range from $39.25 per MWh to $79.00 per MWh until July, when the average cost soared to $122.52 per MWh. In August, the Company paid an average cost of $116.53 per Mwh. *Id*. Average cost than fell to the $30-$40 range, until July 2001 when cost reached $67.53 per Mwh. *Id*. Clearly, the July and August 2001 prices for third party supply are the primary factors responsible for the BGS deferral. *Id.* Two years after EDECA became law, the Company was still struggling to procure energy within a reasonable price range failing the Hope Creek Standard of prudency.

Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board limit BGS cost recovery for the months of July and August 2001 to the average overall BGS cost paid for to-be-divested generation and for NUG power during those months. *RA-2* at 19. The resulting BGS energy disallowance would be $12,820,560 in

July 2001 and $12,706,106 in August 2001, totaling $25,527,000, *RA-2*, Sched. ACC-4 updated.

Review of relevant evidence obtained through discovery showed that the Company failed to aggressively pursue long term parting contracts. In the Final Order the Board allowed the Company, "at its option", to obtain BGS energy and capacity through "parting contracts" and to use financial instruments, such as hedging, to decrease BGS customer exposure to price volatility. *J-1*, Par. 11. The Company was also allowed to "utilize its affiliated service company to make arrangements for BGS supply" with the arrangements to be conducted on behalf of the Company on a regulated basis. *Id*. Atlantic failed to act on any of these viable options, leaving the Company without any long-term contract option and exposing ratepayers to the instability of the spot market.

Atlantic's failure to enter into parting contracts was particularly unreasonable as the Board allowed recovery of over-market costs of contracts. The Board stated that:

> The use of parting contracts entered into by ACE with the purchaser(s) of the Company's generating assets as part of the sale of those assets, to the extent they make possible or enhance the sale of the assets and are approved by the Board, are in the public interest and in accordance with applicable law. . . The Company may flow-through, and fully and timely recover from its customers, the rates specified in the parting contracts and resulting costs. If such rates and costs are above market, they will be recovered through a mechanism similar to the NNC . . .

[*Id*. at 44 Par. 20]

Company witness Jerry Elliott testified that Atlantic knew about the Board's recommendation regarding parting contracts and financial hedging. T243L:22-25. He further testified that the Company understood the mitigating purpose behind the Board's recommendation of parting contracts:

> I think our understanding was that it was Atlantic City Electric's task to try to mitigate the risks as best as possible using all of the various tools that were available to it to do it and that could consist of RFPs. It could consist of fixed purchases which would be hedges against the market prices.

> It could be looked at as far as the parting contracts with divested units or it could be financial hedges. Basically all of these things I think we've spoken to, you know, previously, that those were tools that suppliers or purchasers can use to try to mitigate risk.

[T251:L8-21]

Atlantic understood the purpose of parting contracts, yet the Company failed to use this tool to mitigate the cost of BGS during the Transition Period, resulting in excessive costs charged to ratepayers. The Company's failure to act prudently regarding the matter of parting contracts is yet another reason to disallow the Company's excessive BGS costs.

b. Excess Capacity

The Company's failure to plan is further evidenced by its sale of excess capacity during the Transition Period. As shown in *RA-2*, Sched. ACC-5 updated, Atlantic's third party capacity costs increased significantly in June 2001. That increase corresponds to the capacity contracts into which the Company entered in the Spring of 2001. During those months the Company possessed excess capacity and failed to sell it at rates sufficient to cover acquisition costs. *RA-2,* Sched. ACC-3. Therefore, ratepayers paid for high-priced capacity while Atlantic sold excess capacity below cost. *Id*. at 19.

The Auditors recognized that, during the RFP period from January 2000 through May 2000, the Company was a net seller of energy. T29:L25-930:L5. RFP I requested 775 MW of capacity. *AUD-2* at VII-29. ACE's actual capacity requirements were much lower. *Id.* ACE entered bilateral contracts for 370 MW during the RFP period, sold capacity in the PJM monthly and daily markets, and still had excess capacity for four of the five months indicated. *AUD-2,* Exhibit VII-19; T929:L25-930:L5; T930:L14.

There is a discrepancy between the Auditors' and Company Testimony's regarding the Company's treatment of excess BGS capacity. The auditors testified that revenues from the sales of excess capacity were credited to the BGS deferral. T930:L9-22**..** However, Company witness Mr. Elliott testified that no credits were made prior to April

2001, because these sales were all non-BGS capacity. T318:L8-20 <u>The Ratepayer Advocate recommends that the accounting treatment of these sales be reviewed and all revenues credited to ratepayers</u>.

The excess capacity included the Company's combustion turbines ("CTs") and the Deepwater facility. T930:L12-14. The Auditors criticized Atlantic's use of the CT and Deepwater facilities:

> ACE's use of Deepwater and Combustion Turbine("CT") capacity for BGS in the August 1999 through July 2000 period was not in compliance with the Final Order that requires the capacity be offered to PJM at market prices. The Company did, however, record the January through July 2000 Deepwater and CT capacity costs based on the PJM monthly clearing price for capacity in lieu of actual plant capacity costs. Accordingly, the deferred balance BGS costs reflect the costs of purchased capacity, rather than the cost of capacity provided by the transferred units. However, ACE made no such adjustment for the period from August 1999 through December 1999.

[AUD-2 at I-11]

BWG also criticized the Company for failing to compare bid results to PJM market prices as requested by the Board. *AUD-2* at VIII-28. The auditors recommended that the Company should be "required to determine the adjustment to its BGS deferral accounts to reduce the Deepwater and CT capacity amounts to reflect PJM monthly clearing prices for 1999." *AUD-2* at I-12*; AUD-2* at VIII-56; T936. They further recommended that "ACE should demonstrate that the capacity provided by these units was needed for BGS in the period August 1999 and July 2000, and exclude the costs associated with any capacity that was not needed." *Id.*

To the extent that the Company secured excess capacity, Atlantic clearly had a responsibility to use its best efforts to sell it at the highest possible price. *Id*. If the Company sold excess capacity below cost, ratepayers should be held harmless from the negative impacts of such a sale. *RA-2* at 20. The Ratepayer Advocate recommends that, with regard to capacity sold during the Transition Period, the Board should disallow $3,375,429, the difference in cost between the Company's average capacity costs and the revenues received from the sale of excess capacity. *RA-2* at 19.

2. Atlantic's Claim for $3,528,000 in Administrative Costs in Its BGS Deferral Should be Disallowed.

As the *Hope Creek* standard requires, the Company bears the burden of showing that its deferred balance costs were reasonably incurred. BGS Auction costs, including supply procurement related expenses, and other administrative costs of the BGS auction, are covered by tranche fees and are paid by the winning supplier of the BGS auction. T762:L11. Consequently, the administrative costs relating to the first BGS auction in February 2002 should have been paid by tranche fees and not charged to ratepayers. T767:L11-12.

The Board's auditors have also recommended disallowances of certain administrative costs. They have found RFPs I and II to have been imprudent; consequently, administrative costs relating to those RFPs should be disallowed. *AUD-2* at VI-12. Due to time constraints BWG was unable to quantify the costs relating to the development & solicitation of bids in the RFP I and II processes. *AUD-2* at 1-12. However, since the auditors have found those processes to be flawed and imprudent, all costs relating to those RFP's should be disallowed. They also recommend that BGS merchant support costs included in the BGS without Board Order be disallowed. *AUD-2* at III-5. From August 1999 to July 2002, BGS merchant support costs represent labor charges relating to BGS activities similar to administrative costs. *Id.* There was no Board Order authorizing BGS merchant support expenses to be charged to deferred balances. *Id.* The auditors therefore recommended the disallowance of $1,397,521 in BGS merchant support costs. *Id.*

Given the lack of substantiating evidence for the Company's proposed administrative costs, as well as the inappropriate booking of auction-related expenses to administrative costs, the Ratepayer Advocate recommends that all BGS Administrative Costs, totaling $3,528,000, should be disallowed.

C. THE AMOUNT OF THE MARKET TRANSITION CHARGE ("MTC") SHOULD BE LIMITED TO PRUDENTLY INCURRED AND FULLY MITIGATED EXPENSES.

1. Net NUG Charge Deferrals

This issue is addressed in Section III. A below.

2. To be Divested Generation

a. The Company Should Not Be Allowed to Recover A Cash Working Capital Allowance for its To-Be-Divested Generation Units.

At the time of the Stipulation in the Restructuring Docket, Atlantic had determined to divest its base load generation facilities. *P-3* at 6. In the Final Order, the Board determined that the to-be-divested facilities should be used to provide BGS until they were actually sold. *J-1* at 87. While the facilities were being used to provide BGS service, the Company was permitted to recover revenue requirements, with interest, of the facilities through the MTC. *Id*. The Company was also permitted a 13% pre-tax return on investment of these assets. *P-3* at 6.

Each month Atlantic calculated a revenue requirement consisting of operating expenses, depreciation and taxes for each plant used to provide BGS. *RA-2* at 33. In addition, a monthly rate base for each unit was determined with the revenue requirement calculation including a 13% pre-tax return on this rate base pursuant to the BPU's Final Order. *J-1* at 92, Par. 22. This calculation included both nuclear units and fossil facilities until October 2000, however, the revenue requirement associated with the nuclear units has been primarily limited to the return on the stranded costs associated with the units since November 2000. *Id.* There was a strong assumption at the time of Restructuring that the Company would sell the fossil unit in March 2003. *Id.* For the period from April 2003 to June 2003 the Company included the return on stranded costs associated with the fossil units. *Id.*

In calculating its rate base associated with the to-be-divested generation, Atlantic included a cash working capital requirement of $7,377,283 for the period from August 1999 through July 2003. *RA-2,* Sched. ACC-9 updated, p. 2 of 2; *P-12*. The Company already receives a return on these funds through the monthly interest it receives on the deferred balance. *Id.* Cash working capital is given to utilities to cover cash outflows between the time that the revenues are received and the time that expense must be paid. Atlantic's claim to recover cash for working capital is in error because when the Company started to accrue interest on the deferred balance, the Company was made whole. No further compensation is necessary.

The Company's cash working capital claim must be discussed with the Company's use of a pre-tax return on rate base of 13% in mind. Interest rates fell to record lows during the transition period, and the return likely exceeded the Company's actual cost of capital during this period. *Id.* Therefore, it is essential that the rate base is not inflated by unjustified claims. *Id*; *NJLEUC -1* at 14. The Company is also earning interest on its deferral over the transition period and will presumably continue to earn interest over the recovery period. Atlantic is already earning interest on certain components of BGS over this period. The Company should not be permitted to realize a "windfall" by recovering for cash working capital.

Moreover, the Company supported its cash working capital claim using the outdated lead/lag study used in the last rate case in Docket No. ER90091090J, which was filed in 1990. *RA-2* at 33-34. The Ratepayer Advocate objects to the inclusion of a cash working capital requirement in the cost of service for these plants, and further objects to the use of a 12-year old lead-lag study that was conducted prior to restructuring. *Id*. Further, Atlantic's used of non-cash depreciation expense should be disallowed. Depreciation does not result in cash outlay by the Company; the Company does not make cash payments for depreciation expenses. *RA-2* at 35. Only items for which actual out-of-pocket cash expenditures must be made should be included in a cash working capital calculation. *Id*.

Atlantic has also failed to include certain cash items in its cash working capital calculations that should have been included such as interest on debt, which are generally made quarterly although the Company is paid monthly. *RA-2* at 36; *NJLEUC-1* at 14.

Given the deferred balance interest to compensate the Company during the transition period, the unsupported lead/lag study, the inclusion of non-cash expenses and the failure to include significant sources of cash working capital in its analysis, the Company's cash working capital claim should be denied. *RA-2* at 37.

b. The Existing 13% Pre-Tax Return on To-Be Divested Generation Should Be Adjusted to the Same Rate of Return That Is Established in the Pending Base Rate Case.

As discussed above, Atlantic has been permitted to earn a 13% pre-tax return on to-be-divested generation. The Company's filing in this matter included an assumption that the fossil units would be sold in March 2003 and that stranded costs associated with these units would continue to be charged to ratepayers at a 13% pre-tax return. *Id.*, p. 40. However, the fossil units have yet to be divested, and there is no evidence that they will be divested in the near future.

Given the decline in interest rates that has occurred over the past few years, there is no evidence that the 13% return in still reasonable. Moreover, reducing the return earned on these plants prospectively would provide an incentive for the Company to mitigate the costs of these units. Accordingly, the Ratepayer Advocate recommends that the Company's return on its to-be-divested generation be limited to the cost of debt found to be reasonable in the Company's current base rate case. *Id*. A limit on the return to the cost of debt will provide a powerful incentive for the Company to resolve the issue of its to-be-divested generation while mitigating the rate impact to New Jersey ratepayers. *Id*.

The recommended revised return on these plants should be effective August 1, 2003. The Ratepayer Advocate is not recommending any retroactive reduction to the return during the Transition Period. If the base rate case is not complete by August 1, 2003, then the Board should make the 13% return interim, subject to refund, based on the final determination of capital costs made in the Company's base rate case.

The Company acknowledges that the Board has the authority to reduce the current 13% return on a prospective basis.

> Mr. Morgan: I assume that the thirteen percent has to stay in place until the Board would take some appropriate action to make modifications.
>
> Judge Sukovich: So basically you are assuming that if the Board wanted to change it as a result of this case it could?
>
> Mr. Morgan: As long as they followed the procedures and there was evidence and witnesses cross-examined and all of that, and if the Board comes up with a different number then the Company would have to deal with that. T95:L23 – T96:L11.

Moreover, since Atlantic is currently using short-term debt to finance its MTC deferral, the appropriate debt rate to apply is the short-term debt rate. Over the Transition Period, the short-term debt rate has generally declined. The most recent rates are 1.47% for Atlantic and 1.99% for its Parent Pepco. *S-5*. Thus the 13% pre-tax return earned by Atlantic is well in excess of the Company's financing costs. The Company has confirmed its use of short-term debt to finance the deferrals in its response to S-CSEC-14:[5]

> The Company's deferred balance has been financed with short-term debt. It is also our intent to continue to finance the deferral with short-term debt.

Atlantic has admitted to financing these deferrals with short-term debt, and has

[5] *S-5*.

stated its intention to continue to do so. Consequently, it is appropriate to reduce the return, effective August 1, 2003, on all to-be-divested generation from 13% to the short-term debt rate.[6]

c. Atlantic's incorrect assumption that the entire BGS supply would be provided through the BGS auction when the Company still owns fossil units resulted in 20% excess supply.

Since August 2002 the Company has had 20% excess energy in its portfolio. The Company bid for 80% supply at the BGS auction, has 20% supply from its NUGs and has 20% supply from its fossil generation facilities for a total of 120% of BGS requirement. *RA-2* at 27. The Ratepayer Advocate recommends disallowance of the revenue requirement associated with the 20% fossil generation. *Id.*

In the BGS Auction Order, the Board specifically required Atlantic to use its NUGs to provide BGS supply:

> . . . Conectiv should reserve a fixed percentage of BGS load and to serve that load by applying its NUG related power (capacity, energy, and ancillary services), using as necessary the procedures previously approved by the Board, to serve that percentage of the BGS load; thus Conectiv would provide full requirements service to a fixed percentage of its BGS load.

[*IMO Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act*, Docket No. EX01050303 (Order dated Dec. 11, 2001) at 25.]

At the BGS auction held in February 2002 Atlantic purchased 80% of its Year 4 Transition BGS requirements. *RA-2* at 37. The Company has stated that when it contracted for its Year 4 BGS supply through the auction, it assumed that its fossil fuel units would be divested prior to the beginning of Year 4. *Id.* Thus, the Company

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[6] On February 18, 2003, the Ratepayer Advocate filed comments addressing the prospective ratemaking treatment of B.L. England with the Board, pursuant to the Board's instructions in an Order dated February 5, 2003. *I/M/O Atlantic City Electric Company - Rate Unbundling, Stranded Cost and Restructuring Filings*, BPU Dkt. Nos. EO97070455, EO97070456, and EO97070457.

assumed that all BGS supply not provided by its NUG contracts would be provided through the auction. *Id.* However, that is not the case. The projected sale of the fossil units has not occurred, and the Company still possesses those units. *Id*; Sched. HAC-11.

The costs associated with the retained fossil generation units are included in Atlantic's deferred balances along with revenues from the sale of excess power. *RA-2* at 39. Therefore, to the extent that the revenue requirement associated with the to-be-divested generation exceeds the revenues received from the excess power, ratepayers are paying higher rates because the Company had excess BGS supply during Year 4. *Id.* Ratepayers should not be forced to pay higher deferred costs because the Company miscalculated the amount of BGS supply purchased through the auction. *Id.*

Ms. Crane was unable to calculate the revenue associated with energy sales from the fossil units because the Company did not provide information which would permit her to evaluate how much excess power was sold and at what price. *Id.* at 39.

Therefore, Ms. Crane has reduced the above-market to-be-divested monthly generation costs included in the MTC to $1,084,00, which is the Company's estimate of the monthly amount associated with its stranded costs. *Id.*

3. Transition-Related Costs

Atlantic has requested recovery of $15,307,000 in restructuring and transition-related costs. HAC-7 updated; HAC-13 updated. There are two categories of such costs: (1) costs associated with an eight-year amortization of estimated capital costs associated with customer care system enhancements; and the balancing and settling system; and (2) estimated costs associated with regulatory restructuring proceedings. In addition to the eight year amortization, Atlantic also included monthly operating costs that it claims relate to customer care, balancing and settlement, and load profiling. *Id.*

The Ratepayer Advocate recommends that these transition costs be disallowed, primarily because as Ratepayer Advocate witness Andrea Crane noted, "the Company just has not justified these costs." T644:L21-24. On Sept. 20, 2002, the Ratepayer Advocate promulgated a discovery request on the Company requesting a breakdown of the amount, the purpose, and the date of each expenditure. T644:L22-25. On December 23, the Company finally responded, providing a list of broad categories, such as contractors, internal labor, software and other. T645:L2-7. As Ms. Crane testified:

> . . . they provided no breakdown, no description of what these costs were for. No listing of what contractors were involved. No specific — no invoices. No requests for proposals, for obtaining contractors. No work products from these contractors.
>
> They indicated in their data request response that the detail requested would require considerable additional research and would not be available for a considerable period of time.

[T6445:L6-16].

The Company failed to provide supporting invoices for actual costs to the Ratepayer Advocate. T645:L2-7. As Ms. Crane stated, "[y]ou can't ask for several million dollars of costs without providing some support for those dollars." T646:L11-13.

Many of the restructuring costs charged by the Company were incurred prior to the beginning of the transition period on August 1, 1999. T646:L2-4. The Company has acknowledged that at least until August 1, 1999 costs were still being billed through bundled rates. T646:L5. Consequently, the Company most likely recovered restructuring costs through whatever rates were in effect at that time. T636:L6-8.

The Company has failed to meet its burden of proof. Without justification of costs, there can be no determination regarding the reasonableness of these expenditures. Accordingly, the Company's request for transition costs should be completely disallowed.

4. Customer Account Proceeding Costs

In its order in the Customer Accounts Services proceeding, Docket No. EX99090676, the Board approved a stipulation that stated:

> All Market Development Fund costs, as defined in Atlantic City Electric Company (Atlantic) Attachment "C", shall be charged against the $1.2 million of over-collected Gross Receipts and Franchise Tax addressed in the Board Order of June 7, 2000 Docket No. EX00050299. If it becomes apparent that the $1.2 million is inadequate to absorb the Market Development Fund costs, the Company reserves the right to file a proposal for a supplemental recovery mechanism with the Board. . .Atlantic shall file a verified petition with the Board in order to establish the reasonableness of the following start-up costs...incurred to develop consolidated billing....

[*IMO Electric Discount and Energy Competition Act of 1999-Customer Account Services,* Docket No. EX99090676 (Order dated December 22, 2000), Att. E.]

The stipulation also provided that such deferred costs be recovered over no more that a two-year period beginning August 1, 2003. *J-3* at Attachment E, p. 2(c).

Atlantic has provided no evidence in this case that it has incurred any Market Development Fund costs. *RA-2* at 41. Consequently, there should be no offset for these phantom costs. The Company has not filed a verified petition in support of its consolidated billing costs; Company witness Mr. Chalk stated in his Direct Testimony that the deferred balance petition was the first time Atlantic had addressed these costs since the EX99090676 docket. *P-11* at 13; *RA-2* at 41. The Company has provided no testimony regarding the reasonableness of its consolidated billing costs. *RA-2* at 41. Nor is the Company's proposed treatment of such costs in this case consistent with the requirement that any such deferred costs be recovered over a period of two years. *RA-2* at 41-42. In this case, Atlantic is proposing to recover the costs over a period of four years, its proposed amortization period for the entire Deferred Balance. *Id.* Again, the Company has failed to meet its burden of proof, under N.J.S.A. 48:2-21(d), by failing to provide any supporting evidence as the evidentiary record reflects.

Given that no support for these costs has been provided and that the proposed recovery period exceeds the period required by the stipulation, the Ratepayer Advocate recommends that no part of the $1.2 million in over-collected GR&FT funds be applied to this account and that the entire amount of consolidated billing costs be disallowed. *RA-2* at 42; ACC-8 updated.

III. NET NON-UTILITY GENERATION CHARGE ("NNC")

The Company's updated deferred NNC balance shows an over-recovery of $6,365,000 compared to its filed position. *RA-2*, Sch. ACC-1 updated. The Ratepayer Advocate makes specific recommendations in connection with the Company's obligation to mitigate the NUG contracts and the disallowance of the $2.477 million for the Logan Arbitration.

A. FORECAST COSTS.

At the beginning of the Transition Period, Atlantic had four Board-approved NUG contracts: Pedricktown, DRMI, Carney's Point and Logan. *RA-2* at 27. Two of the NUG contracts have since been bought out or bought down. The Pedricktown contract, a 30-year contract commencing in February 1992, providing 106 MWs of capacity and energy, was bought out effective December 27, 1999 for the sum of $228, 500,000. The DRMI contract, a 25-year contract commencing in September 1991, provided 75 MWs of capacity and energy and was renegotiated in 2000, reducing the cost of the contract by approximately $1.5 million annually. In 2001, the total cost of the DRMI contract was $33.4 million. *Id*. The Board approved recovery of the buyout plus financing fees from ratepayers. *Id.*

The Carney's Point contract, a 30-year contract commencing in March 1994, provides approximately 180 MWs of capacity and energy. In 2001, the total annual cost of the capacity and energy was $67.1 million. That contract has neither been bought out nor bought down. *Id.*

The Logan contract, a 30-year contract commencing in January 1995, provides for 200 MWs of capacity and associated energy. The annual payment to Logan in 2001 was $109.9 million. *Id*. The Logan contract has been a matter of dispute and was recently the subject of arbitration. The outcome of this matter is still undecided.

Atlantic has indicated that it is discussing additional restructuring buyouts or buydowns of its NUG contracts; however, it has failed to provide any information regarding such discussions. *RA-2* at 30. The Pedricktown buyout and the DRMI buydown were submitted to the Board for approval in September 1999 and June 2000 respectively, but no mitigation of NUG contracts has occurred for over two years. *Id.* at 31. The Ratepayer Advocate questions whether the Company has been as diligent in pursuing mitigation efforts as it should have been in order to mitigate the above-market costs charged to ratepayers.

The Ratepayer Advocate recommends that the Company be required to report its NUG mitigation activities annually simultaneously with its annual NNC rate filing. *RA-2* at 31. This will permit the Board and the parties to assess the Company's mitigation efforts and to determine if Atlantic is using its best efforts to mitigate. *Id.* If the Board determines that the Company is not making a good faith effort to mitigate costs, then the Board should take all appropriate steps to reduce rates to ratepayers that resulted from above-market NUG contracts. *RA-2* at 32.

B. ALL COSTS OF THE LOGAN ARBITRATION SHOULD BE DISALLOWED PENDING RESOLUTION OF THE MATTER AND BOARD REVIEW OF COSTS.

As discussed above Atlantic has a 30-year agreement with Logan, a non-utility generator, to provide the Company with 200 MWs of capacity and associated energy.

RA-2 at 27. The Company has alleged that it has been overcharged by Logan by approximately $3 million. *RA-2*, App. C. This dispute was submitted to arbitration and the Company received a favorable judgment that Logan still disputes. Company witness Chalk testified that "the Logan billings are being reviewed retroactively back to February 9, 2000 for recalculation." T425:L12-17. In addition, prospectively the Company is seeking clarification with regard to heat rate testing standards that it believes will also result in lower rates. The Auditors reviewed the Logan documentation and concluded that no estimate of costs was available. AUD-2 at IV-5. They noted that the Company expected that as a result of Logan adjustments, NUG Contract Costs will be reduced in Phase II of the Audit. *Id*.

The Ratepayer Advocate has eliminated all costs associated with the Logan arbitration because the Company has not included any associated expense reductions or revenue increases associated with this litigation. *RA-2* at 29. At the present time we only have one side of the cost/benefit equation. *Id*. While the Company claims that it has spent over $2.4 million to date on the Logan arbitration, we do not know the extent to which the costs incurred by the Company were prudent relative to the likely outcome of this case. *Id*. While the Company indicated that it believed there were past overcharges of $3 million, it did not quantify the likely benefit to be derived from the prospective changes with regard to heat rate testing standards. *Id. at 30*. Nor do we know the total costs that are expected to be incurred as a result of this litigation. *Id*. As the Auditors have noted, adjustments to the NNC are expected to be made in Phase II of the Audit. AUD-2 at IV-5.

The Ratepayer Advocate recommends that the $2,477,000 in Logan arbitration costs be eliminated from the Company's deferred balance. These costs should be considered for recovery only when the litigation is resolved and the parties can better evaluate whether the costs were justified in light of the overall financial benefit to ratepayers.

IV. SOCIETAL BENEFITS CHARGE

A. STARTING BALANCE

Currently the Company is collecting through the Societal Benefits Charge costs associated with the Company's Demand Side Management Programs, Nuclear Decommissioning funding and Uncollectable Accounts. (Direct Testimony of Herbert Chalk, p. 15) For each of these components of the SBC, the monthly revenues are compared to actual expenses and the difference is accumulated in the SBC deferral account for that component. *Id.* For the period from August 1999 through July 2003, the Company has projected a cumulative DSM under recovery deferral of $1,386,000 million; a cumulative deferred under-recovery of $7,798,000 in the Uncollectible Account; and an over-recovery of $30,293,000 in the Nuclear Decommissioning Deferral account. Sched. HACR-14, pp. 1-3. The total deferred credit balance associated with the SBC is $21,108,000.[7] The Company has proposed that this credit balance be netted from the claimed BGS and NNC under-recovery deferred balances and recovery over a four year period.

The Company is also proposing four changes to the components of the SBC. The Company seeks to set the components of the SBC at "the appropriate levels in order that the costs associated with those unbundled rate elements are collected on a current basis. *P-1* at 1. The Company proposes, first, to add a component for the recovery of Universal Service Fund ("USF") contributions for the 2002 interim program. The Company is also proposing a mechanism for the treatment of future USF expenditures. Second, the Company has proposed an adjustment to the Demand Side Management

[7] The Company did not update their exhibits fully to reflect current SBC accumulated credit, therefore the Ratepayer Advocate reflected the SBC credit of $21,108,000 as of 7/31/03 for this brief.

("DSM") rate to recover costs associated with the Comprehensive Resource Analysis (CRA")[8] costs on a prospective basis. Third, the Company proposes to include an SBC component for the recovery of four years of local and statewide Consumer Education expenses, with interest. And fourth, the Company has proposed to eliminate the Nuclear Decommissioning Charge. The Company suggests that each of these rate components will be re-set on an annual basis and subject to true-up based on the prior period recovery balance. *J-14* at 3. The Ratepayer Advocate recommends that all deferred balance and credits attributable to the SBC and accrued during the transition period be netted out. The remaining SBC credit due to ratepayers because of the large nuclear decommissioning overcollection should be refunded to customers over one year. Each of these proposals will be discussed below.

B. UNIVERSAL SERVICE FUND

In its initial filing, Atlantic proposed to recover $557,757 in 2002 Universal Service Fund ("USF") interim program costs and $45,513 in associated interest through a separate ten month[9] USF charge component of the SBC beginning August 1, 2003. *JFJ-5*. The Company has also proposed that future USF expenditures would be subject to deferred accounting and a true up process.

The Ratepayer Advocate recommends that the SBC deferred balance over-recovery be applied to the 2002 interim program USF balance and that the Board determine additional USF funding in a separate proceeding. The Auditors did not comment on the Company's USF proposal.

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[8] CRA was renamed New Jersey Clean Energy Program by Board Order dated February 5, 2003.

[9] The Company is proposing recovery over a ten month period in this filing so that when these rates are next set, the rate change would be effective on June 4, 2004, simultaneously with the already existing winter/summer rate change and the proposed changes to BGS rates . Petition at 1.

C. NEW JERSEY CLEAN ENERGY PROGRAM FUNDING

In its inital filing the Company has projected a cumulative New Jersey Clean Energy Program (DSM) under recovery deferral of $1.386 million for the period from August 1999 through July 2003. Sched. HACR-14. As noted above, the Ratepayer Advocate recommends that this under recovery be included with the other SBC elements and that the balance of the total over recovery should be credited to ratepayers. *RA-2* at 47.

On a prospective basis, the Company proposes changing the current rate to recover $9.5 million in projected Clean Energy Program costs. *RA-2* at 9. The Ratepayer Advocate recommends that this component not be changed at this time but rather changes to this component should be addressed in a separate proceeding. The Company's calculations are based on projected sales and projected spending levels. There are on-going proceedings at the Board to address DSM costs and procedures for all the State's utilities. Any determination regarding the collection of prospective DSM cost within the SBC at this time would be premature and would more properly come out of those DSM proceedings.

Furthermore, in reviewing the DSM invoices, the Auditors noted that supporting contracts and invoices for certain recorded expenses were under the name of an ACE affiliated company within the Conectiv Group. *AUD-2* VI, p. 6 The Auditors noted that although the nature of the expenses related to the DSM costs, these costs could have also been incurred by other affiliated companies. *Id*. At 7. While the Auditors did not adjust the DSM balance to reflect these inaccurate documents, the Auditors did recommend that in the future the Company should have the contract and invoice under the ACE name or the Company should provide additional documentation to show that the costs are in fact related to ACE program costs. *Id.* The Ratepayer Advocate agrees and request that your Honor and the Board Order the Company to do so in the future.

D. UNCOLLECTIBLES

The Company has projected a deferred under-recovery of $7,798,000 in the Uncollectible Account for the period from August 1999 through July 2003. Sched. HACR-14. This sum should be included in the total SBC account, which, as noted above, is over-recovered.

The Auditors determined that the Company's allowance for doubtful accounts exceeded by $1,417,412 the required allowance of $9,906,357. *AUD-2* at VI-6. The Auditors noted that the Company acknowledged that this account was in excess of the required allowance. *Id*. Accordingly, the Auditors recommended that the SBC deferred balance should be reduced by $1,417,412 to reflect this overage. The Ratepayer Advocate adopts this recommendation and has included this additional credit in its updated schedules.

E. CONSUMER EDUCATION PROGRAM ("CEP")

1. Background of the Consumer Education Program

By Order dated September 22, 1998[10], the Board established a consumer education program to educate consumers on the impending changes that would result from deregulation of the electric and gas markets pursuant to the EDECA. The Board was required to establish a multi-lingual electric and gas consumer education program, with the goal of educating residential, small business, and special needs consumers concerning restructuring of the electric power and gas industries. *See N.J.S.A.* 48:3-85(d).

The Board in its May 29, 1998 Order created the Utility Education Committee

[10] *I/M/O the Energy Master Plan Phase II Proceeding to Investigate the Future Structure of the Electric Power Industry,* BPU Docket No. EX94120585Y, Order on Consumer Education, (Sept. 22, 1998). ("September 22, 1998 Order@).

(AUEC”) which represented the interests of the electric and gas utilities, and the Energy Education Council (“EEC”), which represented the interests of consumers.[11] The Board gave the UEC responsibility for developing and implementing the statewide consumer education program. The EEC was given a minor “consulting” role, but the ultimate decision-making power was left with the UEC. By Order dated August 11, 1999, the Board retained the Center for Research & Public Policy of Hartford, Connecticut (“Center”) to advise the Board and to research the level of consumer awareness of energy deregulation and restructuring. The Center was required to present its findings on the effectiveness of the statewide CEP and also make recommendations for improvements to the Board.

By Order dated October 15, 1999, the Board adopted performance standards and benchmarks that were called “Measures of Success,” which were subject to review and refinement as necessary to assess the success of the CEP. These actions were consistent with *N.J.S.A.* 48:3-85(d), which requires the Board to “promulgate standards for the recovery of consumer education program costs from customers which *include* reasonable measures and criteria to judge the success of the program enhancing customer understanding of retail choice.” (*emphasis added*). Subsequently, the June 23, 2000 Order established filing procedures for utilities that were planning to file for CEP cost recovery. The Board relied on their previous ruling in the restructuring proceedings, which stated that CEP costs would be recovered through the societal benefits charge (“SBC”). The CEP cost recovery filings would be accompanied by public notice and a public hearing in compliance with *N.J.S.A.* 48:2-32.2 and *N.J.S.A*. 48:2-32.4. The Board further recognized that evidentiary hearings would be needed to assess the reasonableness and prudence of the cost levels incurred to achieve the Board approved

[11] The Ratepayer Advocate was a participating member of the EEC.

Measures of Success. *See* June 23, 2000 CEP Order at 3.

Since the implementation of the CEP, the electric and gas utilities have been deferring costs for both the statewide and local CEP campaigns. Winning Strategies, the UEC's consultant, billed the utilities for the statewide program based on its determination as to the appropriate allocation between electric and gas utilities generally, and then, by utility, based on the utilities' number of customers. *Id*. Each utility paid for its own local campaign.

2. The Company Did Not Demonstrate Compliance With the "Reasonable and Prudent" Standard For Years 1, 2, and 3.

The Company is seeking recovery of CEP costs in Years 1, 2, 3 and 4 without making the requisite showing that the costs were reasonably and prudently incurred. Schedule JFJ-4 attached to Mr. Janocha's testimony indicates that the Company is requesting $1,580,361 (including $377,108 of local program costs) for its Year One recovery, $1,180,228 (including $389,089 of local program costs)[12] for its Year Two recovery, and $615,576 for its Year Three recovery, which is all state program costs. The Company has also requested for recovery of $26,000 for Year 4 projected expenses. The Company has also included $512,350 in interest expense. The total amount requested by the Company is $3,914,516.

The Company has not attempted to establish the reasonableness and prudence of these expenditures. The Company merely notes that in Petitions to the Board in August of 2000 and in January 2001, "citing the success of the CEP, requested approval of the recovery of CEP costs for the initial two years of the program. *P-14* at 11. The Company further notes that "recovery of year three and year four expendutures have been included in this filing. *Id*. The Company claims that "[r]ecovery of year four costs would be

[12] Ratepayer Advocate consultant Andrea Crane has indicated her belief that the total should be $1,180,728, as the ACE total does not include one $500 local invoice.

contingent upon Board approval that appropriate measures of CEP success for that period have been met." *Id*. At 12

However, the determination that CEP costs are reasonable and prudently incurred does not rest on the attainment of the Measures of Success or performance standards for a particular year. Even if the Measures of Success are achieved, there must be a showing that all costs incurred were reasonable and prudent. The Board in its June 25, 1999 Order stated that it would look to "the extent these [expenditures] represent prudently incurred expenses." Only then will the utilities be permitted to recover the CEP costs in a manner consistent with EDECA. Accordingly, the Company's recovery of costs is dependent on the Board's determination of prudence. This important step cannot be circumvented. Simply stated, the fact that the Measures of Success were attained does not by itself indicate that the Company's CEP expenses in achieving that target were reasonable and prudently incurred. It merely indicates that minimum benchmark levels were achieved for the performance standards established by the Board to measure the success of the CEP.

From the inception of the CEP, the Board contemplated the manner in which utilities would be able to recover reasonably incurred expenses associated with carrying out the objectives of the CEP. By Order dated June 25, 1999[13], the Board began to lay the foundation for CEP cost recovery. The Board ordered that any electric or gas public utility that had incurred expenses related to the CEP would be able to defer those expenses, to be recovered at a later date, according to a two-part test. First, the CEP expenses must meet the standards for measures of success to be developed by the Board, and, second, the CEP expenses must have been prudently incurred, a determination also

[13] *I/M/O the Consumer Education Program on Electric Rate Discounts and Energy Competition*, BPU Docket NO. EX99040242, Decision and Order, (June 25, 1999). (AJune 25, 1999 Order@).

to be made by the Board. *See* June 25, 1999 Order at 2. Again in April 2002[14], the Board restated the position taken in its October 15, 1999 and June 23, 2000 Orders allowing utilities to recover their CEP costs through the SBC. The Board repeated that in order for utilities to recover CEP expenses, the utility must file with the Board and be subject to public and evidentiary hearings. The Board decided to proceed in this manner because ACEP cost recovery through the SBC will result in an increase to the SBC now or at the time the deferral ceases and recovery commences in the case of electric utilities.@ *See* April 8, 2002 Order at 3. After establishing that public hearings would be held regarding CEP cost recovery through the SBC, the Board reiterated its position that, A[t]he reasonableness and prudence of the cost levels incurred to achieve the Board approved measures of success will need to be assessed in reviewing the SBC filings. *Id*.

Prudence requirements are imposed on a public utility's ability to recover costs in order to encourage efficient managerial behavior. *See El Paso Natural Gas Co. v. FPC,* 281 F.2d 567, 573 (5th Cir.), *cert denied*, 366 U.S. 912 (1960). According to New Jersey law and Board precedent, the utility must prove that all costs incurred were reasonable and prudent before these costs can be collected from ratepayers. *See N.J.S.A*. 48:2-2(d).

The Board in *Hope Creek* disallowed recovery of specific costs because the company had not established that the costs were reasonably incurred. As noted earlier, in the *Hope Creek Order*, the Board set forth the two-part standard of review for a prudence determination. The standard provides that before a cost can be recovered in rates, each Company must: 1) show that the Company's actions meet the reasonable person standard given the specific circumstances at the time decisions were made; and 2) show the reasons why each cost was incurred and the benefit to ratepayers by the Company's actions. In effect, the prudence review determines whether the Company performed in a

[14] *I/M/O the Consumer Education Program on Electric Rate Discounts and Energy Competition*, BPU Docket NO. EX99040242, Order of Extension, (April 8, 2002). ("April 8, 2002 Order").

manner that was reasonable at the time, and allows regulators to prevent unreasonable costs from being passed on to ratepayers.

The Measures of Success relied on so extensively by the utilities were only a benchmarking tool, used to measure the level of awareness energy customers achieved through the education program. They were never intended to replace the prudence standard. In this proceeding, Your Honor and the Board must ascertain whether the costs expended to achieve the task were prudently incurred. In order for the utilities to show that they prudently incurred these expenses, the Company must meet the two-part prudence test as stated in the *Hope Creek Order*.

Throughout the consumer education proceedings there has been no Board scrutiny of CEP costs. The Company presented no testimony in this proceeding demonstrating that they satisfied the *Hope Creek* prudence standard. Instead, the Company incorrectly relied upon the attainment of the Measures of Success. Because no assessment of the Company's cost levels ever took place, the Company is not permitted to substitute other components or phases of the CEP to show compliance with the prudence standard. As stated previously, the utility bears the burden of proving that their costs are reasonable and prudently incurred, and in this case, the Company has failed to present evidence sufficient to meet its burden.

3. Even Under The Company's Erroneous Position That Achieving Measures of Success Is Synonymous With Prudence, The Failure of the Statewide CEP to Satisfy the Measures of Success Established by the Board Should Preclude Cost Recovery.

Even if Your Honor and the Board were to determine that the achievement of the Measures of Success was equivalent to prudence, the fact that the statewide CEP failed to achieve its objectives for Year 2 and Year 3 should necessarily preclude the recovery of costs incurred by the Company in those two years. And, as no determination has been made regarding the achievement of the Measures of Success for Year 4, the projected Year 4 expenses should also be disallowed.

The Board hired the Center to conduct research on the level of awareness of gas and electric consumers regarding energy deregulation and restructuring. In order to evaluate consumer awareness in different areas, the Center developed performance standards and benchmarks referred to as Measures of Success**.** The Year 1 Measures of Success were accepted by the Board by Order dated October 15, 1999[15] and focused mainly on increasing consumer awareness of deregulation and choice of alternate energy suppliers.[16] However, Year 1 Measures of Success were changed in Year 2 and Year 3 to reflect later developments in the energy market.

Year 2 of the consumer education program failed to raise the awareness of gas and electric consumers of competition and the ability to switch to alternate energy suppliers, which was vital to the success of the program. The Ratepayer Advocate expressed its concerns to the Board in a letter dated January 11, 2001, which stated that the continued focus on deregulation in Year 2 was inappropriate given the high awareness levels achieved in Year 1, and recommended that the CEP should instead

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[15] *I/M/O the Consumer Education Program on Electric Rate Discounts and Energy Competition*, BPU Docket No. EX99040242, Decision and Order, (Oct. 13, 1999).

[16] The Year 1 Measures of Success were as follows:

A. **Awareness** - awareness of deregulation across all market segments of at least 70%. This would include the General Consumer Market (GCM), Hispanic Consumer Market (HCM), African-American Consumer Market (AACM), Small Business, Low Income, Seniors and the Disabled.

B. **Knowledge** - at least a 50% correct knowledge level of deregulation facts across the four-core markets: GCM, HCM, AACM, and Business.

C. **Selection Process Awareness** - at least a 30% Avery of somewhat aware@ level for the supplier selection process.

D. **Decision Making** - at least a 30% level of making a conscious decision to switch, not to switch or not to decide.

E. **Call Center Satisfaction** - at least 80% satisfaction level among consumers utilizing the NJ Energy Choice call center.

F. **Response to Recommendations** - CEP campaign officials are to respond to any recommendations made in the Center=s reports which are endorsed, accepted and forwarded by the Board in memo form only.

focus on the benefits of deregulation such as increased competition and a choice of energy suppliers. *See* Exhibit A. However, the data compiled by the Center for Year 2 of the CEP indicated that consumers were still very much in the dark about alternate suppliers and their pricing plans as well as information on the mechanics of making a switch.[17] Equally problematic was consumer ignorance of the term Aprice-to-compare@ and how this information could be used to shop around for a new supplier.[18] Therefore, it came as no surprise when the Center revealed in its Sixth Report to the Board that the switching activities of consumers in Year 2 did not meet its benchmark target for residential markets. Switching statistics continued to show a steady decline in Year 3, as shown in the Center's Seventh Report.[19] Presumably, if more consumers were provided with information that would give them the necessary tools to research their switching options, make a decision, and initiate a change in energy providers, then residential switching numbers would have increased**,** not decreased, in Years 2 and Year 3.

In Year 3, because of sharp increases in energy prices, the Ratepayer Advocate recommended that the statewide component of the CEP should be re-directed to address concerns related to high energy costs. *See* Exhibit B (Feb. 15, 2001 letter to Board). This would include providing information to consumers about the reason for high energy costs, advising consumers of ways to manage their energy usage and energy bills, and

[17] The Fifth Report submitted to the Board by the Center showed a 10% decline in the number of consumers who were very or somewhat aware of the process to follow in selecting an energy supplier. In addition, the Fifth Report also revealed that 55.4% of consumers were still waiting for more information in order to make a decision to switch to a energy supplier. Fifth Report at 8.

[18] The Center in its Sixth Report to the Board acknowledged the need to provide consumers with the necessary information so that they may make a switch and recommended that Aconsumers need to be taught by both utilities and the CEP how to find and just what their price-to-compare is. This may be a very large barrier to participation. Nearly 100% of consumers don=t know what or how to find what they pay per-kilowatt hour or per-therm.@ See Center=s Sixth Report at 12.

[19] The Seventh Report revealed declining levels of switching activities among consumers. For example, 96.9% of all respondents could not name or estimate the amount they pay per kilowatt hour which serves as a barrier to shopping. Approximately 60% of respondents were still not familiar with the term price-to-compare and how to use this information in making a decision to switch. Also, only 6.6% of respondents had actively shopped around for a new energy supplier. See Seventh Report at 8.

increasing awareness of financial assistance for which consumers may be eligible. Although Year 3 of the statewide CEP did include Measures of Success related to consumer awareness of energy conservation and efficiency, as well as the availability of financial assistance,[20] these Measures of Success were very general and not detailed or specific enough to be truly effective in ensuring that consumers had the necessary information to respond to high energy costs. These shortcomings became very obvious when the Center's Seventh Report to the Board revealed that the CEP fell short of Year 3 goals in the areas of awareness of conservation/efficiency and financial assistance. If the conservation and efficiency messages circulated to consumers by the utility were truly effective, then the residential customer average load use would show a decrease. In fact, the Board's statistics indicate that, in Year 3, the overall load per customer increased from .0048 MW/customer in May 2001 to .0051MW/customer in April 2002. *See* Exhibit C. Clearly, the Year 3 efforts were not successful in this regard.

In conclusion, the statistics from both Year 2 and Year 3 demonstrate that the CEP failed to increase awareness among gas and electric customers in the critical areas of competition, switching to alternate energy suppliers, energy conservation and efficiency, and the availability of financial assistance to eligible consumers. The apparent foible in the CEP was its continued focus on the message of deregulation in Year 2 and Year 3 when there were issues of greater concern worthy of consumers= attention. Therefore, it is improper to allow utilities to recover these CEP costs for Year 2 and Year 3, when the statewide CEP failed to achieve its Measures of Success in the aforementioned areas. It follows that if ratepayers did not benefit from the CEP during Year 2 and Year 3, utilities should not be permitted to recover from ratepayers costs

[20] The specific measures were general consumer awareness that: (1) A[l]ocal utilities have energy conservation and efficiency programs;@ and (2) A[f]inancial assistance programs are available to help low income households pay their energy bills. See Seventh Report at 33.

associated with a failed program. And, because no determination has been made regarding the Company's Year 4 program, the estimated costs that the Company has included in its filing for Year 4 CEP costs should also be disallowed.

Accordingly, the Company's proposed SBC rate component for the recovery of the CEP costs should be disallowed.

F. Nuclear Decommissioning Charge

The Company has collected from ratepayers over $30 million in nuclear decommissioning costs that were not incurred. The Company has proposed to eliminate this component from the SBC rate.

The Ratepayer Advocate recommends that this over-recovery be used to offset under-recovery in the USF and DSM accounts and then the balance of $21,500,000 be returned to ratepayers in the form of a one time credit.

V. METHOD OF COLLECTION OF DEFERRED COSTS

A. THE SBC OVERRECOVERY SHOULD BE CREDITED FIRST TO THE UNIVERSAL SERVICE FUND ("USF") BALANCE, WITH THE REMAINDER CREDITED TO RATEPAYERS, WITH INTEREST, OVER ONE YEAR.

Atlantic has projected an over-recovery in the SBC totaling $20,083,000 which must be credited to ratepayers. Sched. HAC-1 updated. The Company is proposing that the SBC deferred credit balance be included in the four-year recovery proposed for its other deferred balances, i.e., the BGS, NNC, and MTC. The Company is thus not distinguishing between the deferral relating to its acquisition of energy supply (BGS, NNC and MTC) and its other deferred costs. *RA-2.*

EDECA and its amendment provide options for recovery of certain BGS-related deferrals that are not available for SBC costs. *Id.* at 46. For example, certain costs associated with the BGS deferral may be eligible for securitization, whereas SBC costs are not. *Id*. Consequently, it is appropriate to evaluate SBC deferrals separately from the other deferrals in determining an appropriate recovery or refund mechanism. *Id.*

The Ratepayer Advocate recommends that the SBC net over-recovery[21] be offset by the 2002 USF costs shown in Company Schedule P-14, Sched. JFJ-5., which eliminates the need to establish a USF charge effective August 1, 2003. *RA-2* at 47.

The Board should separately address the issue of recovery of prospective USF costs. *Id.* The remaining SBC credit balance should be returned to ratepayers over a period of one year, with interest, through an appropriate rate element *Id.* at 47.

B. AMORTIZATION OF DEFERRED COSTS IN ORDER TO MITIGATE RATE SHOCK, ATLANTIC'S PROPOSED FOUR-YEAR DEFERRED BALANCE RECOVERY PROPOSAL SHOULD BE REJECTED, AND THE 10-YEAR RECOVERY PROPOSAL RECOMMENDED BY MR. ROTHSCHILD SHOULD BE ADOPTED.

Atlantic's proposal for recovery of its deferred balance relies on a truncated recovery period and applies the interest rate to a balance that is considerably higher than the actual amount it has to finance. The combined effect of the shortened recovery period and an excessive total interest cost would result in unreasonable increases in rates for electric service, if Atlantic's proposal were adopted. In contrast, the recovery proposal recommended by Ratepayer Advocate witness James Rothschild extends the amortization period, locks-in the interest rate at a level reflective of the Company's borrowing costs, and considers tax effects of the expenses and revenues associated with

[21] As noted in the staring SBC balance section, undercollection for uncollectibles and DSM have been deducted from the Nuclear Decommissioning over collection.

the deferred balance, thereby mitigating the rate impact of recovery on Atlantic's ratepayers. *See RA-18*.

The Company proposes to use a four-year amortization period, with the accrual interest rate set annually. *P-3*, pp. 9-10. In contrast, Mr. Rothschild's deferred balance amortization recommendation (1) lengthens the recovery period four-years to 10-years, and (2) locks-in the accrual interest rate at the beginning of the recovery period, instead of setting the rate annually. Additionally, Mr. Rothschild's recognizes the income tax deferral associated with the deferred balance amount and appropriately adjusts the amount of the deferred balance subject to interest accrual. As demonstrated below, Mr. Rothschild's recovery recommendations would mitigate the impact of rate increases for Atlantic's customers and should be adopted.

In an oral ruling at its agenda meeting of March 20, 2002, the Board further clarified the issues to be decided in the instant case. Among the issues identified for determination at the OAL "of what the prudently incurred deferred balance is along with the recommendation of what the rate treatment should be pending the Board's Final Decision . . . until such time as any bonds are sold".[22] For the reasons set forth in more detail below, the Ratepayer Advocate recommends that the 10-year amortization proposal set forth by Mr. Rothschild, and the resulting rates, should be adopted by Your Honor and the Board as the proper going-forward ratemaking treatment of the Company's deferred balance.

[22] *See* I/M/O PSE&G, BPU Dkt. No. ER02050303; I/M/O Atlantic City Electric Company, d/b/a Conectiv, JCP&L, PSE&G, and Rockland Electric Company , BPU Dkt. Nos. ER02080510, ER02080507, ER02080604, and ER0208614 (Oral ruling, March 20, 2003). T2-3 (Item 1A-Audits, 3/20/03). Attached herewith as Exhibit D.

1. The Amortization Period Should Extend to 10-Years.

Amortization of the deferred balance over a four-year period, as proposed by Atlantic, would result in an unreasonable rate increase for its ratepayers. Atlantic witness Joseph F. Janocha testified that Atlantic's ratepayers would face a deferral-related rate increase of 5.09%, assuming a deferred balance of $176,667,198. *P-14*, Sched. JFJ-7. While the percentage increase attributable to the Company's deferred balance amortization proposal is significant in itself, it is especially burdensome when considered in the context of the Company's other proposals. For example, the proposed deferral amortization related-increase would occur at a time concurrent with a proposed one-year credit elimination and potential increases in the Company's MTC factor, resulting in a overall increase of 8.41%, as set forth in the Company's filing. *P-14*, Sched. JFJ-7, p. 1.

Mr. Rothschild examined the Company's amortization proposal. For purposes of illustration, Mr. Rothschild performed numerous calculations using the Company's deferred balance estimate of $176,777,198. *R-18*, pp. 3-4. Mr. Rothschild concluded that extending the amortization period from four-years to 10-years produced a steep drop in rates.[23] *Id*., Table 2, pp. 12-13. Mr. Rothschild found that using a 10-year amortization period instead of a four-year period would significantly lower the annual charge to recover the deferred balance, from 0.5770 cents per kWh to 0.2603 cents per kWh. *Id.*, p. 9. Clearly, the 10-year amortization period recommended by Mr. Rothschild results in significant savings for Atlantic's ratepayers vis-à-vis the Company's four-year amortization proposal.

The Ratepayer Advocate respectfully submits that the rate increase mitigation offered by a longer recovery period outweighs any vague concerns about the impact of a longer recovery period on the Company's ability to borrow more money. Although the

[23] While amortization of the balance over a period longer than 10-years is possible, Mr. Rothschild found that the rate impact of extending the amortization period beyond ten years was more gradual. *Id*., p. 13.

Company raised a concern about the impact of a longer recovery period on its borrowing capacity, it has not quantified such claimed impact. *P-5*, p. 16. Mr. Rothschild testified at hearing that the Company did not provide balance sheet, cash flow statements, and coverage ratio information in support of its contention that an extended recovery period would impact its borrowing capacity. T839:L2-11.

Moreover, as Mr. Rothschild noted at hearing, during the recovery period the Company will have positive cash flow related to the deferred balance, in contrast to the Transition Period when the deferred balance was increasing in amount. In its prophecy of gloom, the Company fails to consider the impact of a positive cash flow stemming from the recovery of the deferral through rates in the post-transition period. Under both the four-year and 10-year recovery proposals, the Company would have positive cash flow related to the deferred balance, all else equal. However, the magnitude of the cash flow will vary over time, as noted by Mr. Rothschild:

> The Company … under my proposal would have a smaller cash flow for the first four years and then would have a larger cash flow for the next six years to pay off the remaining debt. T845:L6-9.

Moreover, as further noted by Mr. Rothschild, the shift from a negative cash flow during the Transition Period to a post-transition period positive cash flow would only help, and not harm Atlantic's borrowing capacity, as reflected in its bond rating:

> [T]he comparison that I think is relevant when you are talking about whether or not the Company's bond rating will be harmed is to look at where we are now and look at whether or not things are getting better or worse.
>
> So from that perspective of whether things are going to get better or worse vis-a-vis the current bond rating I think things get better whether it is the Company's four year amortization recommendation or my ten years amortization recommendation. T846:L5-16.

In summary, the Company's claim that its borrowing capacity would be harmed by a shorter recovery period is unsupported in the record. Unlike the Transition Period when borrowing related to the deferred balance was increasing, in the post-transition recovery period the outstanding deferred balance will shrink in size, with a shift in the Company's cash flow from negative to positive. As aptly summarized by Mr. Rothschild, "So as we go forward things will only get better." T838:L12-13. Here, any claimed constraints on the Company's borrowing capacity should be eased in the recovery period by the shrinking deferred balance and positive cash flow.

2. The Accrual Interest Rate Should be Fixed at the Beginning of the Recovery Period.

Both the Company and Mr. Rothschild agree that interest on the deferred amount should accrue at a rate equivalent to the interest rate on seven year constant maturity treasuries,[24] plus sixty basis points. *P-3*, p. 10; *RA-18*, p.17. However, Mr. Rothschild recommends that the rate should be set initially at the time the recovery rate is established by the Board. *RA-18*, p. 17; T841:L10-13. In contrast, the Company proposes to adjust the rate annually throughout the recovery period.

Mr. Rothschild's fixed interest rate recommendation reflects the nature of the deferred balance. During the Transition Period the deferred balance was growing, resulting in negative cash flow and the need for financing to offset the negative cash flow. In contrast, during the recovery period, the deferred balance will decline over time, with a positive cash flow stemming from its recovery through rates. Mr. Rothschild rightly noted that since the full amount of the deferred balance would have already been financed before the recovery period a fixed interest rate should be used, set at the beginning of the recovery period. *RA-18*, p. 9.

Furthermore, using a fixed interest rate would have additional, practical advantages. Mr. Rothschild noted that a fixed interest rate would "have the additional advantages of 1) not having to change the recovery rate annually; and 2) making the non-

[24] As shown in the Federal Reserve Statistical Release on, or closest to, August 1. *P-3*, p. 10.

securitization more directly comparable to the securitization case, because of securitization financing is used, that financing must be accomplished at a fixed rate." *RA-18*, p. 10.

3. The Amount Upon Which the Interest Accrual is Based Should be Adjusted to Reflect Tax Savings.

Mr. Rothschild found that Atlantic's claimed deferred balance is comprised of expenses which the Company could deduct from its federal and state income taxes. *RA-18*, pp. 15-16. Hence, the deductibility of the deferral-related expenses caused a reduction in the Company's current tax liability. The related reduction in the Company's current tax liability works as a offset to the deferred balance, reducing the amount which needs to finance. Mr. Rothschild estimated that out of a total claimed deferred balance of $176,177,198, Atlantic only needed to finance $104,563,713 of that amount, based on an income tax rate of 40.85%. *RA-18*, p. 15. Using a tax rate of 40.85%, the deductibility of expenses comprising the deferred balance reduced the Company's tax liability by $72,213,485 [40.85% x $176,177,198]. *Id*. It is only the difference between $176,177,198 and $72,213,485, or $104,563,713, which the Company needed to finance. *Id.* Atlantic incurs no interest expense on the portion of the total deferral balance financed by an income tax deferral ($72,213,485) and, therefore, that portion of the total deferred balance should be excluded from the amount upon which the interest accrual calculation is made. As recommended by Mr. Rothschild, the Company should only be permitted to earn a return on that portion of the its deferred balance which it had to finance. *Id*.

At hearing, Mr. Rothschild succinctly summarized the rationale for reflecting the tax benefit in the interest accrual calculation:

> The benefit of this approach is to recognize that the portion of the deferred balance which has provided the Company with a current income tax

> deduction is not a portion on which the Company needs to earn interest because the money has been provided interest free by the Internal Revenue Service. T853:L12-18.

4. Atlantic Should not be Permitted to Include a Tax Gross-Up in its Interest Expense Recovery Revenue.

Finally, the revenue associated with the recovery of the interest on the deferred balance should not be subject to an income tax gross-up, as set forth in the testimony of Mr. Rothschild. Mr. Rothschild considered the tax treatment of the deferral-related expenses in the context of the post-Transition Period recovery of the deferred balance. Since the interest expense incurred each year in the recovery period and associated recovery revenue cancel each other out, Mr. Rothschild concluded that it would be improper to add an income tax gross-up to the interest expense recovery revenue. *RA-18*, p. 16.

VI. RATE DESIGN

Company witness Joseph Janocha is proposing that the MTC be based on a uniform energy rates. P-14 at 6. NJLEUC argues that the new proposal will result in intra-class cost shifting and should be rejected in favor of the existing demand and energy calculation. *NJLEUC-1* at 6.

The Ratepayer Advocate recommends that the Company's uniform energy methodology be adopted provisionally, and that the methodology of the MTC be addressed in the rate design portion of the Company's pending base rate case.

VII. CONCLUSION

As demonstrated above and in the testimony of Ratepayer Advocate witnesses, Andrea Crane and James Rothschild, the Ratepayer Advocate respectfully submits that Your Honor and the Board should adopt the following recommendations:

(1) Atlantic's claimed BGS deferral should be reduced from $72,512,000 to $31,989.

(2) Atlantic's claimed NUG deferred over-collection should be increased from $6,365,000 to $9,301,000.

(3) Atlantic's claimed MTC deferred should be reduced from $125,682 to $70,344,000.

(4) Atlantic's claimed SBC overcollection should be increased from $20,083,000 to $21,500,000. The missing revenues from the sale of excess capacity should be Admin. cost RFP I and II disallowed merchant support to disallowed.

(5) The deferred balance recovery period should be extended to ten years;

(6) The interest rate for the term of the recovery period should be set at the beginning of the recovery period;

(7) The amount upon which the interest accrual is based should be reduced to reflect the tax benefit associated with the underlying expenses; and

(8) The interest recovery revenue should not be grossed-up for taxes